MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY
OPERATING PERMIT TECHNICAL REVIEW DOCUMENT

Permitting and Compliance Division
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CHS, Inc.
Laurel Refinery
802 South Highway 212
P.O. Box 909
Laurel, Montana 59044-0909

The following table summarizes the air quality programs testing, monitoring, and reporting requirements applicable to this facility.

Facility Compliance Requirements	Yes	No	Comments
Source Tests Required	X		Methods 5/5B/5F (PM) Methods 6/6C (SO_2) Method 7 (NO_x) Method 9 (opacity) Method 10 (CO) Method 11 (H_2S) Method 18 (VOC)
Ambient Monitoring Required		X	
COMS Required	X		FCC Regenerator
CEMS Required	X		SO_2, H_2S, NO_x, CO
Schedule of Compliance Required		X	
Annual Compliance Certification and Semiannual Reporting Required	X		
Monthly Reporting Required		X	
Quarterly Reporting Required	X		
Applicable Air Quality Programs			
ARM Subchapter 7 Preconstruction Permitting	X		Permit #1821-15
New Source Performance Standards (NSPS)	X		40 CFR 60, Subpart A, Subpart J, Subpart Db, Subpart Kb, Subpart UU, Subpart GGG, Subpart QQQ
National Emission Standards for Hazardous Air Pollutants (NESHAPS)	X		40 CFR 61, Subpart FF
Maximum Achievable Control Technology (MACT)	X		40 CFR 63, Subpart R, Subpart CC, Subpart UUU, Subpart ZZZZ, Subpart DDDDD
Major New Source Review (NSR) – includes Prevention of Significant Deterioration (PSD) and/or Non-attainment Area (NAA) NSR	X		
Risk Management Plan Required (RMP)	X		
Acid Rain Title IV		X	
Compliance Assurance Monitoring (CAM)		X	
State Implementation Plan (SIP)	X		Billings/Laurel SO_2 Control Plan

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SECTION I. GENERAL INFORMATION

A. Purpose

This document establishes the basis for the decisions made regarding the applicable requirements, monitoring plan, and compliance status of emission units affected by the operating permit proposed for this facility. The document is intended for reference during review of the proposed permit by the U.S. Environmental Protection Agency (EPA) and the public. It is also intended to provide background information not included in the operating permit and to document issues that may become important during modifications or renewals of the permit.

Conclusions in this document are based on information provided in the original application submitted to the Montana Department of Environmental Quality Air Resources Management Bureau (Department) by Cenex Harvest States Cooperatives (Cenex) on 07/10/95, the application for renewal submitted by CHS, Inc. (CHS) on May 12, 2006, and subsequent discussions with CHS personnel.

B. Facility Location

The CHS-Laurel Refinery is located at the South ½, Section 16, Township 2 South, Range 24 East, Yellowstone County. This legal description refers to a physical address of 802 South Highway 212, Laurel, Montana.

C. Facility Background Information

Montana Air Quality Permit

On May 11, 1992, Cenex was issued **Permit #1821-01** for the construction and operation of a hydro-treating process to desulfurize Fluidized Catalytic Cracking Unit (FCCU) feedstocks. The existing refinery property lies immediately south of the City of Laurel and about 13 miles southwest of Billings, Montana. The new equipment for the desulfurization complex is located near the western boundary of the existing refining facilities.

The Hydrodesulfurization (HDS) process is utilized to pretreat FCCU feeds by removing metal, nitrogen, and sulfur compounds from these feeds. The proposed HDS unit also improved the quality of refinery finished products including gasoline, kerosene, and diesel fuel. The HDS project significantly improved the finished product quality by reducing the overall sulfur contents of liquid products from the Cenex Refinery. The HDS unit provided low sulfur gas-oil feedstocks for the FCCU, which resulted in major reductions of sulfur oxide emissions to the atmosphere. However, only a minor quantity of the proposed sulfur dioxide (SO_2) emission reductions were made federally enforceable.

The application was not subject to the New Source Review (NSR) program for either nonattainment or Prevention of Significant Deterioration (PSD) since Cenex chose to "net out of major modification review" for the affected pollutants due to contemporaneous emission reductions at an existing emission unit.

The application was deemed complete on March 24, 1992. Additional information was received on April 16, 1992, in which Cenex proposed new short-term emission rates based upon modeled air quality impacts.

The basis for the permit application was due to a net contemporaneous emission increase that was less than the significant level of 40 tons per year for SO_2 and oxides of nitrogen (NO_x). The application referred to significant SO_2 emission reductions that were expected by addition of the HDS project. These anticipated major SO_2 reductions were not committed to by Cenex under federally enforceable permit conditions and limitations. The contemporaneous emission decreases for SO_2 and NO_x, which were made federally enforceable under this permitting action, amount to approximately 15.5 and 23.7 tons per year, respectively. Construction of the HDS/sulfur recovery complex was completed in December 1993, and the 180-day shakedown period ended in June 1994.

Permit #1821-02 was issued on February 1, 1997, to authorize the installation of an additional boiler (#10 Boiler) to provide steam for the facility. Cenex submitted the original permit application for a 182.50-million British thermal unit per hour (MMBtu/hr) boiler on February 9, 1996. This size boiler is a New Source Performance Standard (NSPS)-affected facility and the requirements of NSPS, Subpart Db, would have applied to the boiler. On November 15, 1996, Cenex submitted a revised permit application proposing a smaller boiler (99.90 MMBtu/hr). The manufacturer of the proposed boiler had not been identified; however, the boiler was to be rated at approximately 80,000 pounds (lbs) steam/hour with a heat input of 99.9 MMBtu/hour. The boiler shall have a minimum stack height of 75 feet above ground level. The boiler will be fired on natural gas until November 1, 1997, at which time Cenex will be allowed to fire refinery fuel gas in the boiler. The requirements of NSPS, Subpart Dc, apply to the boiler. The requirements of NSPS, Subpart J and GGG, also applied as of November 1, 1997. Increases in emissions from the new boiler were detailed in Section IV of the permit analysis for Permit #1821-02. Modeling performed showed that the emissions increase would not result in a significant impact to the ambient air quality (see Section VI of the permit analysis).

Cenex also requested a permit alteration to remove the SO_2 emission limits (Section II.E.2.a of Permit #1821-01) for the C-201B compressor engine because the permit already limits C-201B to be fired on either natural gas or unodorized propane. Cenex also requested that if the SO_2 emission limits could not be removed, the limits should be corrected to allow for the combustion of natural gas and propane. The Department altered the permit to allow for burning odorized propane in the C-201B compressor.

Cenex also requested a permit modification to change the method of determining compliance with the HDS Complex emitting units. Permit #1821-01 required that compliance with the hourly (lb/hr) emission limits be determined through annual source testing and that the daily (lb/day), annual (ton/yr), and ARM 17.8, Subchapter 8, requirements (i.e., PSD significant levels and review) be determined by using actual fuel-burning rates and the manufacturer's guaranteed emission factors listed in Attachment B. Cenex requested to use actual fuel-burning rates and fixed emission factors determined from previous source test data in order to determine compliance with the daily (lb/day) and annual (ton/yr) emission limits. The Department agreed that actual stack testing data is preferred to manufacturer's data for the development of emission factors. However, the Department required that the emission factor be developed from the most recent source test and not on an average of previous source tests. The permit was changed to remove Attachment B and rely on emission factors derived from the most recent source test, along with actual fuel flow rates for compliance determinations. However, in order to determine compliance with ARM 17.8, Subchapter 8, Cenex shall continue to monitor the fuel gas flow rates in both scf/hr and scf/year.

This permit (#1821-02) was written to maintain the language from the HDS Complex Permit #1821-01, where possible, and to separate the HDS Complex Permit #1821-01 requirements from the requirements for the current action (Boiler #10). The permit requirements from Permit #1821-01 were included in Permit #1821-02.

On June 4, 1997, Cenex was issued **Permit #1821-03** to modify emissions and operational limitations on components in the Hydrodesulfurization Complex at the Laurel refinery. The unit was originally permitted in 1992, but has not been able to operate adequately under the emission and operational limitations originally proposed by Cenex and permitted by the Department. This permitting action corrected these limitations and conditions. The new limitations established by this permitting action were based on operational experience and source testing at the facility and the application of Best Available Control Technology (BACT). The following emission limitations were modified by this permit.

Source	Pollutant	Previous Limit	New Limit
SRU Incinerator stack (E-407 & INC-401)	SO_2	291.36 lb/day	341.04 lb/day
	NO_x	2.1 ton/yr 11.52 lb/day 0.48 lb/hr	3.5 ton/yr 19.2 lb/day 0.8 lb/hr
Compressor (C201-B)	NO_x	18.42 ton/yr	30.42 ton/yr
		6.26 lb/hr	7.14 lb/hr
	CO	16.45 ton/yr	68.6 ton/yr
		5.15 lb/hr - when on natural gas	6.4 lb/hr - when on natural gas
	VOC	6.26 ton/yr	10.1 ton/yr
Fractionator Feed Heater (H-202)	SO_2	0.53 ton/yr	4.93 ton/yr
		0.135 lb/hr	1.24 lb/hr
	NO_x	6.26 ton/yr	8.34 ton/yr
		1.43 lb/hr	2.09 lb/hr
	CO	3.29 ton/yr	6.42 ton/yr
		1.00 lb/hr	1.61 lb/hr
	VOC	0.26 ton/yr	0.51 ton/yr
Reactor Charge Heater (H-201)	SO_2	0.214 lb/hr	1.716 lb/hr
		0.79 ton/yr	6.83 ton/yr
	NO_x	9.24 ton/yr	11.56 ton/yr
		2.11 lb/hr	2.90 lb/hr
H-201 (cont.)	CO	4.86 ton/yr	8.89 ton/yr
		1.40 lb/hr	2.23 lbs/hr
	VOC	0.39 ton/yr	0.71 ton/yr
Reformer Heater (H-101)	SO_2	0.128 lb/hr	2.15 lb/hr
		0.48 ton/yr	3.35 ton/yr
	NO_x	6.16 lb/hr	6.78 lb/hr
	VOC	0.24 ton/yr	0.35 ton/yr
Old Sour Water Stripper	SO_2	304.2 ton/yr	290.9 ton/yr
	NO_x	125.7 ton/yr	107.9 ton/yr

Emission limitations in this permit are based on the revised heat input capacities for units within the HDS. The following changes were made to the operational requirements of the facility.

Unit	Originally Permitted Capacity	New Capacity
SRU Incinerator stack (E-407 & INC-401)	4.8 MMBtu/hr	8.05 MMBtu/hr
Compressor (C201-B)	1600 HP (short term) 1067 HP (annual average)	1800 HP (short term and annual average)
Fractionator Feed Heater (H-202)	27.2 MMBtu/hr (short term) 20.4 MMBtu/hr (annual avg.)	29.9 MMBtu/hr (short term) 27.2 MMBtu/hr (annual avg.)
Reactor Charge Heater (H-201)	37.7 MMBtu/hr (short term) 30.2 MMBtu/hr (annual avg.)	41.5 MMBtu/hr (short term) 37.7 MMBtu/hr (annual avg.)
Reformer Heater (H-101)	123.2 MMBtu/hr (short term and annual avg.)	135.5 MMBtu/hr (short term) 123.2 MMBtu/hr (annual avg)

It was determined that the emission and operational rates proposed during the original permitting of the HDS unit were incorrect and should have been at the levels Cenex was now proposing. Because of this, the permit action and the original permitting of the HDS had to be considered one project in order to determine the permitting requirements. When combined with the original permitting of the HDS, the emission increases of NO_x and SO_2 would exceed significant levels and subject this action to the requirements of the NSR/PSD program. During the original permitting of the HDS complex, Cenex chose to "net out" of NSR and PSD review by accepting limitations on the emissions of NO_x and SO_2 from the old sour water stripper (SWS). Because of the emission increases proposed in this permitting action, additional emission reductions had to occur. Cenex proposed additional reductions in emissions from the old SWS to offset the increases allowed by this permitting action. These limitations would reduce the "net emissions increase" to less than significant levels and negate the need for review under the NSR/PSD program. The new emission limits for SO_2 and NO_x from the old SWS are 290.9 and 107.9 tons/year, respectively.

This permitting action also removed the emission limits and testing requirements for particulate matter less than 10 microns (PM_{10}) on the HDS Heaters (H-101, H-201, and H-202). These heaters combust refinery gas, natural gas and PSA gas. The Department determined that potential PM_{10} emissions from these fuels were minor and that emission limits and the subsequent compliance demonstrations for this pollutant were unnecessary. Also removed from this permit were the compliance demonstration requirements for SO_2 and volatile organic compounds (VOCs) when the combustion units are firing natural gas. The Department determined that firing the units solely on natural gas would, in itself, demonstrate compliance with the applicable limits.

This action would result in an increase in allowable emissions of VOC and carbon monoxide (CO) by 4.7 ton/yr and 60 ton/yr, respectively. Because of the offsets provided by reducing emissions from the old SWS, this permitting action would not increase allowable emissions of SO_2 or NO_x from the facility.

The following changes were made to the Department's preliminary determination (PD) in response to comments from Cenex.

1. The emission limits for the old SWS in Section II.D.2 were revised to ensure that the required offsets were provided without putting Cenex in a non-compliance situation at issuance of the permit. The compliance determinations of Section II.G.5 and the reporting requirements of Section II.H.1.d were also changed to reflect this requirement.

2. The CO emission limits for H-201 in Section II.D.6 were revised; the old limits were inadvertently left in the PD. The table in Section I.B of the analysis was also changed to reflect this.

3. Section III.E.2 was changed to clarify that the firing of natural gas would show compliance with the VOC emission limits for Boiler #10.

4. Section F of the General Conditions was removed because the Department had placed the applicable requirements from the permit application into the permit.

5. Numbering had been changed in Section III.

Permit #1821-04 was issued to Cenex on March 6, 1998, in order to comply with the gasoline loading rack provisions of 40 CFR 63, Subpart CC - National Emission Standards for Petroleum Refineries, by August 18, 1998. Cenex proposed to install a gasoline vapor collection system and enclosed flare for the reduction of hazardous air pollutants (HAPs) resulting from the loading of gasoline. A vapor combustion unit (VCU) was added to the product loading rack. The gasoline vapors would be collected from the trucks during loading, then routed to an enclosed flare where combustion would occur. The result of this project would be an overall reduction in the amount of VOCs (503.7 tons per year (tpy)) and HAPs emitted, but CO and NO_x emissions would increase slightly (4.54 tpy and 1.82 tpy).

The product loading rack was used to transfer refinery products (gasoline, burner and/or diesel fuels) from tank storage to trucks, which transport gasoline and other products, to retail outlets. The loading rack consisted of three arms, each with a capacity of 500 gallons per minute (gpm). However, only two loading arms were presently used for loading gasoline at any one time. A maximum gasoline-loading rate of 2000 gpm, a maximum short-term rate, was modeled to account for future expansion.

Because Cenex's product loading rack VCU was defined as an incinerator under MCA 75-2-215, a determination that the emissions from the VCU would constitute a negligible risk to public health was required prior to the issuance of a permit to the facility. Cenex and the Department identified the following hazardous air pollutants from the flare, which were used in the health risk assessment. These constituents are typical components of Cenex's gasoline.

1. Benzene
2. Toluene
3. Ethyl Benzene
4. Xylenes
5. Hexane
6. 2,2,4 Trimethlypentane
7. Cumene
8. Napthalene
9. Biphenyl

The reference concentration for Benzene was obtained from EPA's IRIS database. The ISCT3 modeling performed by Cenex, for the hazardous air pollutants identified above, demonstrated compliance with the negligible risk requirement.

On September 3, 2000, **Permit #1821-05** was issued to Cenex to revamp its No. 1 Crude Unit in order to increase crude capacity, improve product quality, and enhance energy recovery. The proposed project involved the replacement and upgrade of various heat exchangers, pumps, valves, towers, and other equipment. Only VOC emissions would be affected by the proposed new equipment. The capacity of the No. 1 Crude Unit was expected to increase by 10,000 or more barrels per stream day.

No increase in allowable emissions was sought under this permit application. The proposed project actually decreased VOC emissions from the No. 1 Crude Unit. However, increasing the capacity of the No. 1 Crude Unit was expected to increase the current utilization of other units throughout the refinery and thus may increase actual site-wide emissions, as compared to previous historical levels. Therefore, the permit included enforceable limits, requested by Cenex, on future site-wide emissions. The limits allowed emission increases to remain below the applicable significant modification thresholds that trigger the NSR program for PSD and Nonattainment Area (NAA) permitting.

The site-wide limits were calculated based on the addition of the PSD/NAA significance level for each particular pollutant to the actual refinery emissions from April 1998, through March 2000, for SO_2, NO_x, CO, PM_{10}, and total suspended particulate (TSP) minus 0.1 tpy, to remain below the significance level. A similar methodology was used for the VOC emissions cap, except that baseline data from the time period 1993 and 1999 were used to track creditable increases and decreases in emissions. The site-wide limits are listed in the following table.

Pollutant	Period Considered for Prior Actual Emissions	Average Emissions over 2-yr Period (tpy)	PSD/NAA Significance Level (tpy)	Proposed Emissions Cap (tpy)
SO_2	April 1998-March 2000	2940.4	40	2980.3
NO_x	April 1998-March 2000	959.5	40	999.4
CO	April 1998-March 2000	430.8	100	530.7
VOC	1993-1999	1927.6	40	1967.5
PM-10	April 1998-March 2000	137.3	15	152.2
TSP	April 1998-March 2000	137.3	25	162.2

For example, the SO_2 annual emissions cap was calculated as follows:

Average refinery-wide SO_2 emissions in the period of April 1998 through 2000, added to the PSD/NAA significance level for SO_2 minus 0.1 tpy =

2940.4 tpy + 40 tpy – 0.1 tpy = 2980.3 tpy = Annual emissions cap.

Permit #1821-05 replaced Permit #1821-04. This was the last permitting action for the initial Title V Operating Permit #OP1821-00.

Permit #1821-06 was issued on April 26, 2001, for the installation and operation of eight temporary, portable Genertek reciprocating engine electricity generators and two accompanying distillate fuel storage tanks. Each generator is capable of generating approximately 2.5 megawatts of power. These generators are necessary because of the high cost of electricity. The operation of the generators will not occur beyond 2 years and is not expected to last for an extended period of time, but rather only for the length of time necessary for Cenex to acquire a more economical supply of power.

Because these generators would only be used when commercial power is too expensive to obtain, the amount of emissions expected during the actual operation of these generators is minor. In addition, the installation of these generators qualifies as a “temporary source” under the PSD permitting program because the permit will limit the operation of these generators to a time period of less than 2 years. Therefore, Cenex would not need to comply with ARM 17.8.804, 17.8.820, 17.8.822, and 17.8.824. Even though the portable generators are considered temporary, the Department required compliance with BACT and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 would be ensured. In addition, Cenex would be responsible for complying with all applicable air quality standards. In order to keep this permitting action below the threshold of nonattainment area permitting requirements, Cenex requested a limitation to keep the project’s potential emissions of SO_2 below 40 tons. Permit #1821-06 replaced Permit #1821-05.

Permit #1821-07 was issued on August 28, 2001, to change the wording in Section VII.A.2, regarding the stack height on the temporary generators, to allow for the installation of mufflers on those stacks, thus increasing the total stack height. In addition, the Department modified the permit to eliminate references to the repealed odor rule (ARM 17.8.315), to correct conditions improperly referencing the incinerator rule (ARM 17.8.316), and to update a testing frequency on the product loading rack VCU based on the Title V permit term. Permit #1821-07 replaced Permit #1821-06.

On June 3, 2002, the Department received a request from Cenex to modify Permit #1821-07 to remove all references to 8 temporary, portable electricity generators. The generators were permitted under Permit #1821-06, with further clarification added in Permit #1821-07 regarding generator stack height. The generators have not been operated since August 10, 2001, and Cenex has no intention of operating them in the future. The references to the generators were removed, and the generators are no longer included in Cenex's permitted equipment. **Permit #1821-08** replaced Permit #1821-07.

On March 13, 2003, the Department received a complete Montana Air Quality Permit (MAQP) Application from Cenex to modify Permit #1821-08 to add a new Ultra Low Sulfur Diesel (ULSD) Unit, Hydrogen Plant, and associated equipment to meet the EPA's 15 parts per million (ppm) sulfur standard for highway diesel fuel for 2006. The permit action removed the Middle Distillate Unifiner (MDU) charge heater, MDU stripper heater, MDU fugitives, and the #3 and #4 Unifier Compressors. The ULSD Unit included two heaters, four compressors, C-901 A/B and C-902 A/B, process drains, and fugitive piping components. The Hydrogen Plant included a single fired reformer heater, process drains, and fugitive piping components.

The treated stream from the ULSD Unit was separated into its constituent fuel blending products or into material needing further refining. The resulting stream was then stored in existing tanks and one new tank (128). Three existing tanks (73, 86, and 117) were converted to natural gas blanketed tanks to reduce emissions of VOCs from the ULSD Unit feed stock product streams. Cenex was to install a new Tail Gas Treatment Unit (TGTU) for both the Sulfur Recovery Unit (SRU) #1 and #2 trains that will be operational prior to startup of the ULSD Unit but technically are not part of this permitting action. **Permit #1821-09** replaced Permit #1821-08.

On July 30, 2003, the Department received a complete MAQP Application from CHS to modify Permit #1821-09. The application was complete with the addition of modeling information provided to the Department on August 22, 2003. CHS requested to add a new TGTU and associated equipment for Zone A's SRU #1 and SRU #2 trains to control and reduce SO_2 emissions from this source. CHS submitted modeling to the Department for a determination of a minimum stack height for the existing SRU #1 and SRU #2 tail gas incinerator stack. CHS also submitted a letter to the Department to change the name on the permit from Cenex to CHS. The permit action added the new TGTU, set a minimum stack height for the tail gas incinerator stack, and changed the name on the permit from Cenex to CHS. **Permit #1821-10** replaced Permit #1821-09.

On June 1, 2004, the Department received two MAQP Applications from CHS to modify Permit #1821-10. The applications were complete with the addition of requested information provided to the Department on June 16, 2004. In one application CHS requested to change the nomenclature for Reformer Heater H-801 to Reformer Heater H-1001. H-801 was previously permitted during the ULSD project (Permit #1821-09), at 150-MMBtu/hr. CHS requested to change the size of Reformer Heater H-801 (H-1001) from 150-MMBtu/hr to 161.56-MMBtu/hr. In the other application CHS requested to increase the PAL for CO from 530.7 tons per year to 678.2 tons per year based on new information obtained by CHS. The new information was obtained after the installation of a CO continuous emission monitor (CEMS) on the FCCU Stack. Emissions of CO from the FCCU Stack were assumed to be zero until the installation of the CEMS. CHS also requested that specific emission limits, standards, and schedules required by the CHS Consent Decree be incorporated into the permit. **Permit #1821-11** replaced Permit #1821-10.

On December 15, 2004, the Department received a letter from CHS to amend Permit #1821-11. The changes were administrative primarily related to changing routine reporting requirements from a monthly basis to quarterly. The changes to the permit were made under the provisions of ARM 17.8.764, Administrative Amendment to Permit. **Permit #1821-12** replaced Permit #1821-11.

On March 28, 2006, the Department issued **Permit #1821-13** to CHS to build a new 15,000-barrel per day (BPD) delayed coker unit and associated equipment. The new delayed coker unit allows CHS to increase gasoline and diesel production by 10-15% by processing heavy streams that formerly resulted in asphalt (asphalt production is expected to decrease by approximately 75%, but the capability to produce asphalt at current levels was maintained and no emission credits were taken with respect to any possible reduction in asphalt production) without increasing overall crude capacity at the refinery. The delayed coker unit produces 800 short tons per day of a solid petroleum coke product. To accommodate the downstream changes created by the new delayed coker unit, several other units will be modified including the Zone D FCC Feed Hydrotreater, FCCU, ULSD Unit, and Hydrofluoric Acid (HF) Alky Unit. Other units will be added: Delayed Coker SRU/TGTU/Tail Gas Incinerator (TGI), Naphtha Hydrotreating (NHT) Unit, NHT Charge Heater, Boiler No. 11, Light Products Railcar Loading Facility, and two new tanks will be added to the Tank Farm. Other units will be shut down: the Propane Deasphalting Unit, Unifiner Compressors No. 1 and 2, No. 2 Naphtha Unifier Charge Heater and Reboiler, BP2 Pitch Heater, and Boilers No. 3 and 4. The VCU associated with the new Light Products Railcar Loading Facility and the Coker Unit TGI were subject to the requirements of 75-2-215, MCA and ARM 17.8.770, Additional Requirements for Incinerators. The Delayed Coker project and associated equipment modifications did not cause a net emission increase greater than significant levels and, therefore, does not require a NSR analysis. The net emission changes were as follows:

Constituent	Total Project PTE (ton/yr)	Contemporaneous Emission Changes (ton/yr)	Net Emissions Change (ton/yr)	PSD Significance Level (ton/yr)
NO_x	39.2	-7.5	31.8	40
VOC	-1.5	-53.3	-54.8	40
CO	106.7	-23.2	83.5	100
SO_2	39.7	0.0	39.7	40
PM	7.6	6.6	14.2	25
PM_{10}	6.7	6.6	13.3	15

The following is a summary of the CO emissions included in the CO netting analysis: Coker project (+106.7 TPY), emergency generator (+0.44 TPY, start-up in 2002), Zone A TGTU project (+8.3 TPY, initial startup at end of 2004), and Ultra Low Sulfur Diesel project (-31.9 TPY, started up in 2005). Permit #1821-13 replaced Permit #1821-12.

On May 4, 2006, the Department received a complete application from CHS to incorporate the final design of three emission sources associated with the new 15,000 BPD delayed coker unit project permitted under Permit #1821-13. The final design capacities have increased for the new NHT Charge Heater, the new Coker Charge Heater and the new Boiler No. 11. The application also includes a request to reduce the refinery-wide fuel oil burning SO_2 emission limitation. This reduction allows CHS to stay below the significance threshold for the applicability of the New Source Review-PSD program. The maximum firing rates are proposed to increase with the current permitting action. The following summarizes the originally permitted firing rates (Permit #1821-13) and the new proposed firing rates for the heaters and the boiler:

NHT Charge Heater: 13.2 to 20.1 MMBtu-LHV/hr (22.1 MMBtu-HHV/hr)
Coker Charge Heater:129.3 to 146.2 MMBtu-LHV/hr (160.9 MMBtu-HHV/hr)
Boiler #11: 175.9 to 190.1 MMBtu-LHV/hr (209.1 MMBtu-HHV/hr)

CHS also requested several clarifications to the permit. Under Permit #1821-13 several 12-month rolling limits were established for modified older equipment and limits for new equipment. CHS requested clarifications be included to determine when compliance would need to be demonstrated for these new limits. Permit #1821-13 went final on March 28, 2006, and CHS is required to demonstrate compliance with the new limitations from this date forward. For the 12-month rolling limits proposed under Permit #1821-13 and any changes to limitations under the current permit action, CHS would be required to demonstrate compliance on a monthly rolling basis calculated from March 28, 2006. For modified units the limitations will have zero emissions until modifications are made. New units will have zero emissions until start-up of these units. Start-up is defined as the time that the unit is combusting fuel, not after the start-up demonstration period. Some units have clearly designated compliance timeframes based on the consent decree. These limitations and associated time periods are listed within the permit.

The Department agreed that the heading to Section X.A.3 can include the "*Naphtha Hydrotreating Unit*"; Section D.1.c is based on a 30-day rolling average; Section X.D.7.a.ii should state that the SO_2 limit is based on a 12-hour average; and that Section XI.E.3 should be revised to remove the requirement for a stack gas volumetric flow rate monitor. The Department made some clarifications to the language in Section X.D.6.b. The Department's intent in permitting the coke pile with enclosures was to ensure that at no time would the coke pile be higher than the top of the enclosure walls at any point on the pile, not only the portion of the pile that is adjacent to the wall.

The Department did not believe it was necessary to designate the Sour Water Storage Tank as a 40 CFR 60 Subpart Kb applicable tank, when currently these regulations do not apply. If CHS makes changes in the future and 40 CFR 60 Subpart Kb becomes applicable to the tank, then CHS can notify the Department and the Department can include the change in the next permit action.

The Department received comments from CHS on the preliminary determination of **Permit #1821-14** on June 21, 2006. The comments were editorial in nature and the changes were made prior to issuance of the Department Determination on Permit #1821-14. CHS requested corrections to the PM, PM_{10}, NO_x netting values in Section II.G of the permit analysis, and the Department agreed that the edits were needed. CHS also requested further clarification to the requirements of Section X.D.6.b of the permit.

CHS stated that the coke pile will be dropped from two coke drums to a location directly adjacent to the highest walls of the enclosure area. The height of the dropped coke piles will not exceed the height of the wall. If CHS is required to relocate and temporarily store the coke at another location within the enclosure area, CHS will not pile the coke higher than the walls adjacent to the temporary storage location. Permit #1821-14 replaced Permit #1821-13.

On September 11, 2006, the Department received an application from CHS to incorporate the final design of emission sources associated with the new 15,000-BPD delayed coker unit project permitted under Permit #1821-13 and revised under Permit #1821-14. The changes include:

- Retaining Boiler #4 operations and permanently shutting down the CO Boiler;
- Modifying the FCCU Regenerator CO limit due to the air grid replacement;
- Rescinding the permitted debottleneck project for Zone D SRU/TGTU/TGI and revising the long term SO_2 potential to emit;
- Modifying the Zone E (Delayed Coker) SRU/TGTU/TGI - Incinerator design and NO_x limits;
- Rescinding the firing rate restriction and associated long-term emission limits, and revising VOC emission calculations for H-201 and H-202; and
- Removing the 99.9 MMBtu/hr restriction and reclassifying Boiler #10 as subject to NSPS Subpart Db.

On October 11, 2006, the Department received a request to temporarily stop review of the permit application until several additional proposals were submitted, which included:

- On October 24, 2006, the Department received a de minimis notification for stack design changes for the Delayed Coker Unit (Zone E) SRU Incinerator.
- On October 31, 2006, the Department received clarification on the ULSD project.
- On November 1, 2006, the Department received a request to limit the maximum heat rate capacity of the #2 N.U. Heater to below 40 MM BTU/hr in conformance with the CHS Consent Decree. CHS also requested that the Department re-initiate review of Permit Modification #1821-15.

All of the above changes allowed CHS to stay below the significance threshold for the applicability of the New Source Review-PSD program. CHS also requested several clarifications to be included in the permit, and the Department suggested streamlining the permit's organization. **Permit #1821-15** replaced Permit #1821-14.

<u>Title V Operating Permit</u>

CHS's Title V **Operating Permit #OP1821-00** was issued final & effective on November 11, 2001.

D. Current Permit Action

On May 12, 2006, the Department received an application for the renewal of Title V Operating Permit #1821-00. The application was deemed administratively complete on June 12, 2006 and technically complete on July 11, 2006. Permit #OP1821-01 incorporates all applicable source changes since the issuance of Permit #OP1821-00, including:

- Addition of three new emitting units: #EU021 (ULSD and Hydrogen Plant), #EU022 (Delayed Coker Unit), and #EU023 (Zone E SRU and TGTU);
- Incorporation of Consent Decree CV-03-153-BLG-RFC requirements. This included updating the Title V Operating Permit with a number of specific new emission limits and monitoring requirements which had been included in the most recent MAQP #1821-15, as well as adding a general requirement for CHS to comply with the relevant applicable terms and conditions of the Consent Decree (most importantly, the Affirmative Relief/Environmental Projects, Subsections A-M, (excluding the stipulated penalty components)); and
- Inclusion of new regulations impacting CHS, including three MACT standards: 40 CFR 63, Subpart UUU, Subpart ZZZZ, and Subpart DDDDD.

Operating Permit #OP1821-01 replaces Operating Permit #OP1821-00.

E. Taking and Damaging Analysis

HB 311, the Montana Private Property Assessment Act, requires analysis of every proposed state agency administrative rule, policy, permit condition or permit denial, pertaining to an environmental matter, to determine whether the state action constitutes a taking or damaging of private real property that requires compensation under the Montana or U.S. Constitution. As part of issuing an operating permit, the Department is required to complete a Taking and Damaging Checklist. As required by 2-10-101 through 105, Montana Code Annotated (MCA), the Department has conducted a private property taking and damaging assessment and has determined there are no taking or damaging implications. The checklist was completed on April 24, 2007.

F. Compliance Designation

An inspection is conducted at CHS on an annual basis. On September 29, 2006, CHS was inspected by the Department and found to be in compliance with applicable requirements.

SECTION II. SUMMARY OF EMISSION UNITS

A. Facility Process Description

CHS is a petroleum refinery located in Laurel, Montana. The refining process distills crude oil using heat. This distillation separates the crude oil into its component parts. The refiner then cracks some of the heavier molecules by applying heat in the presence of a catalyst to make the reaction take place. These raw products are then treated in several ways to take out impurities. Finally, the proper liquids and additives are blended to create the desired product. The major processing equipment includes:

1. Atmospheric and vacuum crude distillation towers
3. Naphtha Hydrotreaters (NHT) (*previously Unifiners*)
4. Platformer (= Naphtha Reformer)
5. Fluidized Catalytic Cracking (FCC) Unit
6. Alkylation/Butamer/Merox/Saturate Units
7. Hydrodesulfurization (HDS) Unit and Hydrogen Plant
8. Four Sulfur Recovery Units (SRUs) with Tailgas Treatment Units (TGTUs)
9. Ultralow Sulfur Diesel Unit and Hydrogen Plant
10. Delayed Coker Unit (*to be installed as part of MAQP 1821-13*)
11. Transfer Facilities (Truck Product Loading, Railcar Product Loading)

B. Emission Units and Pollution Control Device Identification

Emission Unit ID	Description	Pollution Control Device/Practice
EU001	Plant-wide and Multiple Emitting Unit Limitations	Permit #1821-05 Limits, Billings/ Laurel SO_2 Stipulation, and MACT LDAR program, where applicable. CEMS on Refinery Fuel Gas Header(s).
EU002	#1 Crude Unit and Naphtha Splitter • #1 Crude Unit Preheater (CV-HTR-1) • #1 Crude Unit Main Heater (CV-HTR-2) • #1 Crude Unit Vacuum Heater (CV-HTR-4)	LDAR, Billings/ Laurel SO_2 Stipulation
EU003	#2 Crude Unit • #2 Crude Unit Main Heater (2CV-HTR-1) • #2 Crude Unit Vacuum Heater (2CV-HTR-2)	LDAR, Billings/ Laurel SO_2 Stipulation
EU004	PDA Unit – *SHUTDOWN*	
EU005	Naphtha Hydrotreater Unit • NHT Charge Heater (H-8301) • NHT Reboiler Heater #1 (H-8302) • NHT Reboiler Heater #2 (H-8303) • NHT Splitter Reboiler Heater (H-8304) • #2 Naphtha Unifiner Charge, Reboiler Heater – *to be removed as part of 1821-13* • #1 Unifiner Compressor Engine – *to be removed as part of 1821-13* • #2 Unifiner Compressor Engine – *to be removed as part of 1821-13*	LDAR, Billings/ Laurel SO_2 Stipulation
EU006	Middle Distillate Unifiner – *SHUT DOWN*	
EU007	Platformer Unit • Platformer Heater (P-HTR-1) • Platformer Debutanizer Reboiler Heater (P-HTR-2) • Platformer Recycle Compressor Turbine (C-4772)	LDAR, Billings/ Laurel SO_2 Stipulation

EU008	Fluid Catalytic Cracking (FCC) Unit • FCC Charge Heater (FCC-Heater-1) • FCC Regenerator (FCC-VSSL-1)	LDAR, SO_2 CEMS, Billings/ Laurel SO_2 Stipulation
EU009	Alkylation/Butamer/Merox/Saturate Units • Alkylation Unit Hot Oil Belt Heater (ALKY-HTR-1) • Miscellaneous Process Vent (Alkylation Unit Butamer Stabilizer Offgas)	LDAR, Billings/ Laurel SO_2 Stipulation
EU010	Hydrodesulfurization Unit and Hydrogen Plant (100 Unit) • Reformer Heater (H-101) • Reactor Charge Heater (H-201) • Fractionator Feed Heater (H-202) • Hydrogen Compressor Gas Engine (C-201B)	LDAR, Permit #1821-05 Limits, Low NO_x Technology (on heaters), Billings/ Laurel SO_2 Stipulation
EU011	Zone D Sulfur Recovery Unit (SRU) and Tail Gas Treatment Unit (TGTU) • SRU Reheater (E-407) • Incinerator (INC-401)	Permit #1821-05 Limits, Low NO_x Technology, SO_2 CEMS, Billings/ Laurel SO_2 Stipulation
EU012	Zone A SRU and TGTU • #1 SRU Incinerator (SRU-AUX-4)	SO_2 CEMS, Billings/ Laurel SO_2 Stipulation
EU013	Steam Generation Units • #1 Fuel Oil Heater (CV-HTR-9) • #4 Boiler • #5 Boiler • #9 Boiler • Boiler #10 • Boiler #11	Permit #1821-05 Limits Fuel Oil Flow Meters (#3, #4, #5 Boilers) LDAR and Low NO_x Technology (Boilers #10 and #11), Billings/ Laurel SO_2 Stipulation
EU014	Tank Farm (non-Wastewater): • *MACT Group 1 Storage Vessels* • *MACT Group 2 Storage Vessels* • *Exempt – pressure vessels* • *Exempt – not organic HAP* • *Exempt – not refining*	Internal and External Floating Roofs, Fixed Roofs, LDAR (as applicable), Billings/ Laurel SO_2 Stipulation
EU015	Transfer Facilities • Asphalt Loading Heater #1 • Truck Product Loading Rack Vapor Combustion Unit (VCU) • Railcar Product Loading Rack VCU	VCU on Light Product Truck Loading Rack and Railcar Loading Rack LDAR, Billings/ Laurel SO_2 Stipulation
EU016	Wastewater Treatment Units • Wastewater Treatment Unit (old) • Wastewater Treatment Unit (new) • Tanks: Tank 23, Tank 25, Tank 44, Tank 118, Tank 119, Tank 128, and Tank 129 • New Wastewater Treatment Unit Vessels	Enclosed conveyance and other wastewater controls for affected equipment per NSPS QQQ; Floating roofs per NSPS Kb
EU017	Flare Systems • Refinery Flare (FL-7202) • Zone E Coker Flare (FL-7201)	Flare, Billings/ Laurel SO_2 Stipulation
EU018	RCRA Units	Restrictions on Land Tillage (HSWA permit)
EU019	Cooling Towers • Cooling Towers #1 - #3 • Cooling Tower #5 • Cooling Tower #6	None
EU020	Saturate Gas Concentration Unit – *Eliminate EU, naphtha splitter consolidated with EU002*	

EU021	Ultra Low Sulfur Diesel (ULSD) (900 Unit) and Hydrogen Plant (1000 Unit) • Reactor Charge Heater (H-901) • Fractionator Reboiler (H-902) • Reformer Heater (H-1001)	LDAR
EU022	Delayed Coker Unit – *proposed operation as part of 1821-13* • Coker Charge Heater (H-7501) • Coke Processing Operations	LDAR, reasonable precautions for coke processing
EU023	Zone E SRU and TGTU – *proposed operation as part of 1821-13*	LDAR

C. Categorically Insignificant Sources/Activities

Appendix A of Permit #OP1821-01 lists insignificant emission units at the facility. The permittee is not required to update a list of insignificant emission units; therefore, the emission units and/or activities may change from those specified in Appendix A.

SECTION III. PERMIT CONDITIONS

A. Emission Limits and Standards

Emission limits and standards in the Title V permit were established from preconstruction permits, the Billings/Laurel SIP, NSPS requirements, NESHAP requirements, MACT requirements, and the USEPA Consent Decree entered February 2004. CHS currently has 27 active preconstruction permits. The following is a list of those permit numbers: #9-091868, #56-091569, #55-091569, #105-042970, #129-062270, #272-061171, #363-112971, #364-112971, #362-112971, #499-102372, #540-030773, #664-112073, #665-112073, #674-121973, #800-041675, #1111, #1161, #1176, #1175, #1168, #1169, #1170, #1173, #1174, #1317, #1552, #1821-05. Permits #14-110768, #1171, and #1172 were revoked.

B. Monitoring Requirements

ARM 17.8.1212(1) requires that all monitoring and analysis procedures or test methods, required under applicable requirements, be contained in operating permits. In addition, when the applicable requirement does not require periodic testing or monitoring, periodic monitoring must be prescribed that is sufficient to yield reliable data from the relevant time period that is representative of the source's compliance with the permit.

The requirements for testing, monitoring, recordkeeping, reporting, and compliance certification sufficient to assure compliance, does not require the permit to impose the same level of rigor for all emission units. Furthermore, it does not require extensive testing or monitoring to assure compliance with the applicable requirements for emission units that do not have significant potential to violate emission limitations or other requirements under normal operating conditions. When compliance with the underlying applicable requirement for an insignificant emission unit is not threatened by lack of regular monitoring and when periodic testing or monitoring is not otherwise required by the applicable requirement, the status quo **(i.e., no monitoring)** will meet the requirements of ARM 17.8.1212(1). Therefore, the permit does not include monitoring for insignificant emission units.

The permit includes periodic monitoring or recordkeeping for each applicable requirement. The information obtained from the monitoring and recordkeeping will be used by the permittee to periodically certify compliance with the emission limits and standards. However, the Department may request additional testing to determine compliance with the emission limits and standards.

C. Test Methods and Procedures

The operating permit may not require testing for all sources if routine monitoring is used to determine compliance, but the Department has the authority to require testing if deemed necessary to determine compliance with an emission limit or standard. In addition, the permittee may elect to voluntarily conduct compliance testing to confirm its compliance status.

D. Recordkeeping Requirements

The permittee is required to keep all records listed in the operating permit as a permanent business record for at least 5 years following the date of generation of the record.

E. Reporting Requirements

Reporting requirements are included in the permit for each emission unit, and Section V of the operating permit, "General Conditions", explains the reporting requirements. However, the permittee is required to submit quarterly reports, semi-annual monitoring and annual monitoring reports to the Department and to annually certify compliance with the applicable requirements contained in the permit. The reports must

include a list of all emission limit and monitoring deviations, the reason for any deviation, and the corrective action taken as a result of any deviation.
To eliminate redundant reporting, a source may reference previously submitted reports (with at least the date and subject of the report) in the semi-annual and annual reports instead of resubmitting the information in quarterly, and/or other reports. However, a source must still certify continuous or intermittent compliance with each applicable requirement annually.

F. Public Notice

In accordance with ARM 17.8.1232, a public notice was published in the *Billings Gazette* newspaper on or before April 27, 2007. The Department provided a 30-day public comment period on the draft operating permit from April 27, 2007, through May 29, 2007. ARM 17.8.1232 requires the Department to keep a record of both comments and issues raised during the public participation process. The comments and issues received by May 29, 2007, have been summarized, along with the Department's responses, in the following tables.

G. Draft Permit Comments

Summary of Permittee Comments

Draft Permit Reference	Permittee Comment	Department Response
Section III.A.26 & A.29 Consent Decree	Certain terms contained in the draft permit are not applicable requirements under Title V and should be removed from the final permit. These draft Permit Terms do not meet the underlying regulatory requirement of ARM 17.8.1211, Section (2) which states: "*Every requirement contained in an air quality operating permit must be based upon the following: …(c) requirements contained in a judicial order or consent decree entered in response to a violation of any rule, requirement, administrative order, or permit that has been promulgated, adopted, or issued pursuant to Title 75, chapter 2, MCA.*" As stated in the above rule, the permit must contain any consent decree requirement that reflects noncompliance with a specific rule or regulatory requirement. In order for the CD requirement to be incorporated into the permit, according to this Montana rule, the CD provision must have been adopted to correct a noncompliance. In establishing the CHS settlement, the parties agreed to incorporate some provisions in the Consent Decree which are "program enhancements." These provisions, listed below [*left out for brevity*], are not reflected in any state or federal rule. CHS could not, and in fact did not, violate these requirements which do not appear in any rule or regulation. Thus, the CD provisions reflected these requirements were clearly not adopted to correct a noncompliance.	The Department does not agree that Section III.A.26 and III.A.29 should be removed from the permit. The intent of the Title V operating permit program is to record all of the air quality requirements that apply to a source in one document. The terms and conditions listed in Section III.A.26 and III.A.29 should remain in the permit, because the Consent Decree is an applicable requirement as defined by ARM 17.8.1201(10) and it contains relevant terms and conditions as required under ARM 17.8.1211(1)(c).

Page 1, list	For consistency, item 1 should be reworded to "Crude Units and Naphtha Splitter". Since the renewal application was submitted, the PDA Unit has been permanently shutdown. It can be removed from this list. Change "Cracker" to "Cracking". Once completed, there will be 4 SRU and 3 TGTU (Zone E not yet completed)	Operating Permit changed as requested.
Page 2, Table EU004 EU013 EU014	This unit has been permanently shutdown. The table should be updated to indicate this. Since the renewal application was submitted, #3 Boiler has been permanently shutdown and Boiler #11 has started up. Tank 60 heater has been shut down as part of the permanent shutdown of the PDA unit (AQP 1821-13). It was inadvertently left off the list of equipment to be shutdown as part of that project. It can be removed from the list of equipment included in this EU.	Operating Permit changed as requested.
Page 8, Item A.26 and A.29	See discussion in text of [CHS] letter	See above discussion.
Page 9 EU001.2.A.1; 2.A.2.b.viii	Note that the #3 boiler has been permanently shutdown.	Operating Permit changed as requested.
Page 10, Table, B7, B8 & B9	Delete reporting requirement B37. It is not related to the SO_2 SIP.	Operating Permit changed as requested.
Page 10, Table B10 Page 11, Table B11 Page 11, Table B11	This requirement (B10) can be deleted because requirement B11 is now effective. Boiler #11 has been started up. Requirement B15 should be added [to table] as it defines how the emissions should be calculated (2.a.). For this reason, requirement B20 is not needed. Requirement B15 should be added [to table] as it defines how the emissions should be calculated (2.a.). For this reason, requirement B20 is not needed. Pollutant/Parameter: The note in parentheses can be deleted because Boiler #11 has been started-up and requirement B11 is effective.	Operating Permit changed as requested, except since B.10 was removed there was no need to reference B.15.
Page 12, B10 Page 12, B11 Page 18, B20	This requirement (B10) can be deleted because requirement B11 is now effective. Boiler #11 has been started up. Boiler #11 has started up. This requirement can be updated to indicate the requirement is now effective. Requirement B20 is not needed. This requirement is already included as part of B15 (2.a.).	Operating Permit changed as requested.
Page 21, Table, C1	Pollutant/Parameter: For consistency, this should be updated to indicate that the opacity requirement applies to the #1 crude unit.	Operating Permit changed as requested.

Page 22,C5	Note that this requirement is found in air quality permit 1821-15 at Section VII.B.1. The applicability date for this requirement was the date of the #1 crude unit expansion, and permit #1821-05, September 3, 2000.	Operating Permit changed as requested, the Department added the applicability reference to ARM 17.8.749.
Page 25, EU004	The PDA Unit has been permanently shutdown. This section can be updated to indicate this and all requirements removed.	Operating Permit changed as requested.
Page 26, New Requirement	An opacity limit of 20% applies to the NHT Charge Heater because it was permitted as a new source in air quality permit 1821-13. This condition should be added to EU005 and included in the table along with requirements F11, F20, F22 – F26.	Operating Permit changed as requested.
Page 26, Table, F3	Reporting requirements F25 and F26 needed to be added to the table.	Operating Permit changed as requested.
Page 26, Table, F9	A recordkeeping requirement for this condition is not included. CHS suggests that certification that no fuel oil has been combusted in the NHT charge heater is adequate recordkeeping.	Operating Permit changed as requested.
Page 26, Table, F9	For consistency with other EUs, reporting requirement F24 should not be include here.	Operating Permit changed as requested.
Page 30, Table, H1	Delete compliance demonstration requirement H7. It does not relate to opacity.	Operating Permit changed as requested.
Page 30, Table, H3	Add reporting requirement H12 to the table.	Operating Permit changed as requested.
Page 32, Table, I1	Compliance Demonstration: The table lists Method 9 as the method, however, requirements I18, I19 and I20 relate to the opacity monitor.	Operating Permit changed as requested.
Page 32, Table, I5, I6 & I7	Delete reporting requirement I42. It is not related to the SO_2 SIP.	Operating Permit changed as requested.
Page 32, Table, I8 & I9	Delete compliance demonstration requirement I24 and reporting requirement I43 because they are SIP requirements. Condition I8 is not a SIP requirement.	Operating Permit changed as requested.
Page 32, Table, I10 & I11	Delete compliance demonstration requirement I27. This is not required for the FCC regenerator.	Operating Permit changed as requested.
Page 32, Table, I11, I12	Delete compliance demonstration requirement I35. This requirement is related to the FCC Charge Heater, not the FCC Regenerator vent. This should also be clarified in the Pollutant/Parameter column of the table as follows: "NO_x from FCC Regenerator."	Operating Permit changed as requested.
Page 33, Table, I15	A compliance demonstration requirement should be added. See requirement F19 as an example (maintain records of heat input, based on fuel gas flow rate monitoring and fuel analysis).	Operating Permit changed as requested.
Page 33, Table, first I18	The statement in the Pollutant/Parameter column is misleading. It implies that all CEMS were previously on the combined FCC Regenerator/CO Boiler stack. The only monitors previously on the combined stack were the SIP SO_2 and flow rate monitors.	Operating Permit changed as requested.
Page 33, Table, 1st & 2nd I18	For consistency with other pollutants, compliance demonstration requirement I25 should be deleted.	The Department disagrees, and has left the reference to the SIP RATA.
Page 33, Table, second I18	An incorrect reporting requirement is listed. Requirement I42 should be deleted and I43 added.	Operating Permit changed as requested.
Page 34, I11	This requirement should be expanded to also include the requirement to comply with 500 ppmvd at 0% O_2 per 1-hour time period. The Permit Limit column of the table should be updated, as well.	Operating Permit changed as requested.

Page 34, I12	The requirement should be reworded to indicate that it applies to the "FCC Regenerator stack".	Operating Permit changed as requested.
Page 34, I13	The condition should read "an ESP" not "and ESP".	Operating Permit changed as requested.
Page 35, I18	The SO_2 monitor is also required by the Consent Decree and NSPS Subpart J. The opacity monitor is also required by NSPS Subpart J	Operating Permit changed as requested.
Page 36, I26	Note that the mass NO_x emission limit for the FCCU regenerator is tons per 12-month rolling average, not pounds per hour.	Operating Permit changed as reflect that the mass emission rate limit is tons per 12-month rolling. Note the RATA data needs to be reported in lbs per hour.
Page 36, I27	This compliance demonstration requirement should be deleted because there are no CO pounds per hour emission limit. Requirement I23 adequately defines the QA/QC requirements associated with this CEMS.	Operating Permit changed as requested.
Page 37, I42.c	In a letter dated May 17, 2007, CHS documented a discussion in which the DEQ agreed that reporting the daily average PM per 1000 lb coke burned would not be required. This change will be requested in the next modification to the refinery's air quality permit. CHS requests that this reporting requirement be removed from the Title V permit.	Operating Permit changed as requested.
Page 38, I42.d	In a letter dated May 17, 2007, CHS documented a discussion in which the DEQ agreed that the reporting requirement should be changed to "daily and monthly NOx averages in ppm, corrected to 0% O_2". This change will be requested in the next modification to the refinery's air quality permit. CHS requests that this reporting requirement be removed from the Title V permit.	Operating Permit changed as requested.
Page 39, Table, J2	Condition J3 should be deleted here. Condition J2 is related to equipment leaks. Condition J3 is a process vent requirement.	Operating Permit changed as requested.
Page 41, Table header	For consistency, delete the word "stack" from equipment descriptions.	Operating Permit changed as requested.
Page 41, Table, K7	Delete compliance determination requirement K33. This requirement is related to stack testing. Stack testing for VOCs from C-201B is not required.	Operating Permit changed as requested.
Page 41, Table, K10	Delete requirements K38 and K46 as they relate to performance testing. Performance testing is not required for SO_2 from H-202. Additionally, the Method column in the table should be updated to read "RFG H_2S CEMS, see Section B."	Operating Permit changed as requested.
Page 41, Table, K11	Add reporting requirement K48.	Operating Permit changed as requested.
Page 41, Table, K15	Delete requirements K38 and K46 as they relate to performance testing. Performance testing is not required for SO_2 from H-201. Additionally, the Method column in the table should be updated to read "RFG H_2S CEMS, see Section B."	Operating Permit changed as requested.
Page 42, Table, K18	Reporting requirement K46 should be added here.	Operating Permit changed as requested.
Page 42, Table, K20 K20	Delete requirements K38 and K46 as they relate to performance testing. Performance testing is not required for SO2 from H-101. Additionally, the Method column in the table should be updated to read "RFG H_2S CEMS, see Section B." Delete recordkeeping requirement K44 (related to fuel oil burning). Condition K20 is related to SO_2 emissions from H-101.	Operating Permit changed as requested.

Page 42, Table, K21	Delete recordkeeping requirement K44 (related to fuel oil burning). Condition K21 is related to NO_x emissions from H-101. Add reporting requirement K46, related to compliance source testing.	Operating Permit changed as requested.
Page 42, Table, K22	Delete recordkeeping requirement K44 (related to fuel oil burning). Condition K22 is related to CO emissions from H-101. Add reporting requirement K46, related to compliance source testing.	Operating Permit changed as requested.
Page 42, Table, K23	Reporting requirement K46 should be added here.	Operating Permit changed as requested.
Page 45, K33	The second paragraph of compliance determination requirement K33 is not applicable for sources in EU010. The source testing language should be replaced with language similar to requirement F15. Additionally, the language from AQP 1821-15 at Section III.E.1. related to natural gas combustion should be added.	Operating Permit changed as requested.
Page 45, K42	CHS believes that generating a log is unnecessary paperwork, especially since a facility modification and air quality permit would be required to burn another type of fuel. CHS believes that certifying that no other fuel has been used in C-201B is adequate recordkeeping.	The Department has required CHS to maintain records to demonstrate compliance with the existing condition. This requirement is consistent with other Title V operating permits.
Page 45, K43	CHS believes that generating a log is unnecessary paperwork. CHS believes that certifying that a CO catalyst was in use is adequate recordkeeping.	See response to Page 45, K42.
Page 45, K44	CHS believes that generating a log is unnecessary paperwork, especially since a facility modification and air quality permit would be required to burn fuel oil in one of these heaters. CHS believes that certifying no fuel oil was burned in H-202, H-201 and H-101 is adequate recordkeeping.	See response to Page 45, K42.
Page 47, Table, L3	Note that the requirements listed are not in numerical order.	The Department has corrected the sequence.
Page 47, Table, L4	Delete compliance determination requirement L17 from this EU. It is not applicable to the SRU/TGTU tail gas incinerator.	Operating Permit changed as requested.
Page 47, Table, L4, L8, L9, L10	Requirement L24 discusses development of emission factors for compliance determination. Compliance with the SO_2 emission limits in condition L4 [and L8, L9, and L10] are determined by the CEMS.	Operating Permit changed as requested. In addition, the Department clarified in L24 that this requirement referred only to NO_x for this emitting unit.
Page 47, Table, L5	Delete compliance determination requirement L17 from this EU. It is not applicable to the SRU/TGTU tail gas incinerator.	Operating Permit changed as requested.
Page 47, Table, L7	The Pollutant/Parameters column should read “Zone D SRU Incinerator (INC-401 & E-407)”.	Operating Permit changed as requested.
Page 47, Table, L8	Delete compliance determination requirement L17 from this EU. It is not applicable to the SRU/TGTU tail gas incinerator.	Operating Permit changed as requested.
Page 47, Table, L8	Delete reporting requirement L35. It is not related to the SO_2 SIP.	Operating Permit changed as requested. In addition, reporting requirement L35 was removed from Table L9 & L10.
Page 47, Table, L9	Delete compliance determination requirement L17 from this EU. It is not applicable to the SRU/TGTU tail gas incinerator.	Operating Permit changed as requested.

Page 47, Table, L10	Delete compliance determination requirement L17 from this EU. It is not applicable to the SRU/TGTU tail gas incinerator.	Operating Permit changed as requested.
Page 47, Table, second L18	For consistency with other EUs, requirement L25 should be added.	Operating Permit changed as requested.
Page 49, Table, second L17	As discussed previously, this requirement is not applicable to the SRU/TGTU tail gas incinerator. It should be deleted entirely from this EU.	Operating Permit changed as requested.
Page 50, L30	CHS believes that generating a log is unnecessary paperwork, especially since a facility modification and air quality permit would be required to burn fuel oil in the incinerator. CHS believes that certifying no fuel oil was burned in the Zone D SRU incinerator is adequate recordkeeping.	See response to Page 45, K42.
Page 52, Table, M3	Need to add a compliance demonstration requirement and a reporting requirement for condition M3. See K26 and K47, respectively, for examples.	Operating Permit changed as requested.
Page 52, Table, M4	For consistency throughout the permit, the reference to 40 CFR 61 Subpart FF (National Emission Standard for Benzene Waste Operation) should be deleted from this EU. It is included the facility-wide requirements as Condition A.17.	Operating Permit changed as requested.
Page 52, Table, M5	Need to add compliance demonstration requirement to requirement M5. See requirement L13 for an example.	Operating Permit changed as requested.
Page 52, Table, M6	Need to add compliance demonstration requirement to requirement M6. See requirement K27 for an example.	The Department added a reference to the existing compliance demonstration requirement M.16.
Page 52, Table, M7, M8 & M9	Delete reporting requirement M38. It is not related to the SO_2 SIP.	Operating Permit changed as requested.
Page 52, Table, M11	Delete compliance demonstration requirement M20. Condition M11 is a ppm limit. Requirement M20 relates to a pound per hour limit.	Operating Permit changed as requested.
Page 53, Table, M13	Delete reporting requirement M38. It is not related to particulate emission rate rule.	Operating Permit changed as requested.
Page 53, Table, second M17	For consistency with other EUs, compliance demonstration requirement M19 should be added.	Operating Permit changed as requested.
Page 53, M2	After final P&ID review and construction of the Zone A TGTU, it was determined that there are no components in the TGTU subject to 40 CFR 60 Subpart GGG. For this reason, condition M2 should be deleted. Additionally, the reference to its applicability should be removed from the refinery's air quality permit the next time it is revised.	Operating Permit changed as requested. If the TGTU, which was built in 2004, ever has components in VOC service then CHS will become subject to 40 CFR 60, Subpart GGG.
Page 53, M4	For consistency throughout the permit, Condition M4 (40 CFR 61 Subpart FF (National Emission Standard for Benzene Waste Operation)) should be deleted from this EU. It is included the facility-wide requirements as Condition A.17.	Operating Permit changed as requested.
Page 54, M13	CHS questions the applicability of this condition to this emitting unit. If determined to be applicable, the language "…shall include the three sour gas streams…" should be changed to "shall include all sour gas streams…" to account for recent and potential future facility modifications.	Operating Permit changed as requested.
Page 55, M25	This requirement should be reworded as follows for consistency with other EUs. "CHS shall monitor compliance with Section III.M.14. by certifying that the SRU-AUX-4 stack remains at a height no less than 132 feet."	Operating Permit changed as requested.

Page 55, M29	This requirement should be deleted. There are no components in this EU subject to NSPS Subpart GGG.	Operating Permit changed as requested.
Page 56, M32	CHS believes that generating a log is unnecessary paperwork, especially since a facility modification and air quality permit would be required to burn decrease the incinerator stack height. CHS believes that certifying the stack height is unchanged is adequate recordkeeping.	See response to Page 45, K42.
Page 56, M33	CHS believes that generating a log is unnecessary paperwork, especially since a facility modification and air quality permit would be required to burn fuel oil in the Zone A SRU incinerator. CHS believes that certifying no fuel oil was burned in the incinerator is adequate recordkeeping.	See response to Page 45, K42.
Page 57, M41	Reporting requirement M41.d. should be deleted. There are no components in this EU subject to NSPS Subpart GGG. Reporting requirement M41.f. should be deleted. It is included in the facility-wide requirements as Condition A.17.	Operating Permit changed as requested.
Page 57, EU013	The #3 Boiler has been permanently shutdown. The reference to this boiler can be removed from the equipment list below the EU title.	Operating Permit changed as requested.
Page 58, Table, N11	Reporting requirement N43 should be added because the VOC emission limits for Boiler #10 are AQP requirements.	Operating Permit changed as requested.
Page 58, Table, N12	The Stack height row of the table needs to be updated. In the Permit Limit column, it should read “Stack height – height no less than 75 feet from ground level”. In the Method column, it should read “Certify”. In the Frequency column, it should read “Ongoing”.	Operating Permit changed as requested. In addition, for consistency the Department changed all “verify” “verification” and “certification” to read “certify.”
Page 59, Table, N25	For consistency with other EUs, reporting requirement N43 should be deleted here.	Operating Permit changed as requested.
Page 61, N21	Compliance Demonstration requirement N21 is not adequate for Boiler #10 or Boiler #11 because both boilers are authorized to combust refinery fuel gas in addition to natural gas. Requirements N27 and N28 discuss VOC compliance demonstration for Boiler #10. However, since VOC testing is not required for Boiler #11, a requirement similar to F17 should be added to this EU and listed in the Table for condition N16.	Operating Permit changed as requested.
Page 62, N34	This requirement should be reworded as follows for consistency with other EUs. “CHS shall monitor compliance with Section III.N.12. by certifying that Boiler #10 operates with low NOx burners and the FGR system and that the stack remains at a height no less than 75 feet above ground level.”	Operating Permit changed as requested.
Page 62, N39	CHS believes that generating a log is unnecessary paperwork, especially since a facility modification and air quality permit would be required to burn fuel oil in boilers 10 and 11. CHS believes that certifying no fuel oil was burned in boilers 10 and 11 is adequate recordkeeping.	See response to Page 45, K42.
Page 62, N40	CHS believes that generating a log is unnecessary paperwork, especially since a facility modification and air quality permit would be required to burn decrease the boiler 10 stack height or alter the FGR system. CHS believes that certifying the stack height and FGR systems are unchanged is adequate recordkeeping.	See response to Page 45, K42.

Page 64, EU014	As stated previously, the Tank 60 heater has been permanently shutdown as part of the PDA unit shutdown (AQP 1821-13). It was inadvertently left off the list of equipment to be shutdown in the air quality permit application.	Operating Permit changed as requested.
Page 64, Table, O3	Compliance demonstration requirements O7 and O8 should be deleted here because they relate to the equipment leak requirements of 40 CFR 63, Subpart CC.	Operating Permit changed as requested.
Page 65, O10	This requirement should be reworded as follows. "CHS shall maintain the records required by 40 CFR 60.115b and 40 CFR 60.116b."	Operating Permit changed as requested.
Page 66, Table, P2, P4 & P5	Delete recordkeeping requirement P25. It is related to stack height.	Operating Permit changed as requested.
Page 66, Table, P3	In the stack height row, the Method column should read "Certify" instead of "Verify" for consistency with other EUs.	Operating Permit changed as requested.
Page 66, Table, P7	There is no compliance demonstration requirement listed for condition P7. A requirement similar to requirement X18 should be added to this EU and the table.	Operating Permit changed as requested.
Page 67, P3	In order for condition P3 to be applicable to both the truck and railcar light product loading racks, the following modifications to the language of P3 need to be made: P.3.f.i.: "40 CFR 63.425(e)" should be changed to "40 CFR 60.505(b)". P.3.f.v.aa.: This requirement should be changed to the language at 40 CFR 63.422c.i. "The tank truck or railcar gasoline cargo tank meets the test requirements in §63.425(e), or the railcar gasoline cargo tank meets applicable test requirements in §63.425(i)."	Operating Permit changed as requested. The Department modified the suggested language for P.3.f.i. by providing the alternative of 40 CFR 63.425(e) or 40 CFR 60.505(b), as applicable.
Page 69, P15	This requirement should be reworded as follows for consistency with other EUs. "CHS shall monitor compliance with Section III.P.3.i. by certifying that the truck loading rack VCU stack remains no less than 35 feet above grade."	Operating Permit changed as requested.
Page 70, P25	CHS believes that generating a log is unnecessary paperwork, especially since a facility modification and air quality permit would be required to burn decrease the truck rack VCU stack height. CHS believes that certifying the stack height is unchanged is adequate recordkeeping.	See response to Page 45, K42.
Page 70, P26	CHS suggests that the language of this recordkeeping requirement be changed to reference the recordkeeping requirements of 40 CFR 63 Subpart A.	The Department changed the recordkeeping requirement to more closely align with other recordkeeping requirements (i.e., Page 45 – K.42, K.43 & K.44). In addition, there is overlap with recordkeeping required under P.24.
Page 71, P31	Certification of compliance with 40 CFR 63, Subpart R should be added to this reporting requirement.	Operating Permit changed as requested.
Page 71, Table, Q2	For consistency throughout the permit, the reference to 40 CFR 61 Subpart FF (National Emission Standard for Benzene Waste Operation) should be deleted from this EU. It is included the facility-wide requirements as Condition A.17.	Operating Permit changed as requested.

Page 72, Q3	Tank 128 and Tank 129 are currently in sour water service and are operated with a layer of diesel on the surface. Thus, they are not currently in volatile organic liquid service and are not subject to 40 CFR 60 Subpart Kb. Upon installation, CHS requested that they be designated as Kb tanks to allow the flexibility to change the service in the future. In the event the service is changed, CHS will begin the required monitoring, recordkeeping and reporting. CHS requests that this be noted in the permit. An alternative would be to remove the references to the specific tanks subject to Subpart Kb from the equipment list, table and Condition Q3.	The Department agrees that it is unnecessary to identify specific tanks, and has removed the reference to them under this condition.
Page 72, Q6	Compliance demonstration requirement Q5 should be deleted. It is included in the facility-wide requirements as Condition A.17.	Operating Permit changed as requested. Note that the condition deleted was Q.6, not Q.5.
Page 72, Q10	Recordkeeping requirement Q10 should be deleted. It is included in the facility-wide requirements as Condition A.17.	Operating Permit changed as requested.
Page 72, Q11	Recordkeeping requirement Q11 should be modified to read: "CHS shall conduct all applicable recordkeeping requirements in accordance with 40 CFR 60.115b and 40 CFR 60.116b."	Operating Permit changed as requested.
Page 72, Q12	The internal floating roof recordkeeping is covered under requirement Q11. Additionally, CHS believes that generating a log for documenting modifications to the submerged fill configuration is unnecessary paperwork. CHS believes that certifying that the tanks operate with submerged fill is adequate recordkeeping.	Operating Permit changed as requested.
Page 72, Q16	Reporting requirement Q.16.c. should be deleted. It is included in the facility-wide requirements as Condition A.17.	Operating Permit changed as requested.
Page 77, T7	CHS believes that generating a log for documenting modification to or malfunction of the coker cooling tower mist eliminator is unnecessary paperwork. CHS believes that certifying that mist eliminators remain in operation as designed is adequate recordkeeping.	See response to Page 45, K42.
Page 78, Table, V2 [and V4, V6, V8, V11, V12, V15, V19, consolidated for brevity]	A compliance demonstration requirement needs to be added to this EU for condition V2, condition V4, condition V6, condition V8 condition V11, condition V12, condition V15, and condition V19	Operating Permit changed as requested.
Page 78, Table, V8	Reporting requirement V37 should be added because it is related to the air quality permit.	Operating Permit changed as requested.
Page 82, V34	CHS believes that generating a log is unnecessary paperwork, especially since a facility modification and air quality permit would be required to burn fuel oil in H-901, H-902 and H-1001. CHS believes that certifying no fuel oil was burned in these heaters is adequate recordkeeping.	See response to Page 45, K42.
Page 83, EU022	The delayed coker unit has not started operation. CHS requests that a note to this effect be added.	Operating Permit changed as requested.
Page 83, Table, W3	A compliance demonstration requirement needs to be added to this EU for condition W3. See K26 for an example.	Operating Permit changed as requested.

Page 86, W18, W19	For consistency throughout the Title V permit, compliance demonstration requirement W18 should be worded similar to requirement F17. For consistency throughout the Title V permit, compliance demonstration requirement W19 should be worded similar to requirement F17.	Operating Permit changed as requested. Note the Department used F.15 for example language as a basis for W.18.
Page 86, W26	CHS believes that generating a log is unnecessary paperwork, especially since a facility modification and air quality permit would be required to burn fuel oil in the coker charge heater. CHS believes that certifying no fuel oil was burned in this heater is adequate recordkeeping.	See response to Page 45, K42.
Page 88, EU023	The Zone E SRU/TGTU/TGI has not started operation. CHS requests that a note to this effect be added.	Operating Permit changed as requested.
Page 88, Table, X1	For consistency with other EUs, reporting requirement X28 should be deleted from this condition.	Operating Permit changed as requested.
Page 88, Table, X5	Delete recordkeeping requirements X25 (Subpart UUU) and X26 (fuel oil) from this condition. They are not applicable here.	Operating Permit changed as requested.
Page 88, Table, X7	Delete compliance determination requirement X11 (Subpart J). It is not applicable to the NOx limits.	Operating Permit changed as requested.
Page 89, X5	The phrase "…200 ppm, rolling 12-hour average corrected to 0% O2 on a dry basis or…" can be deleted from this condition. It is repeated in condition X6.	Operating Permit changed as requested.
Page 89, X15	This compliance determination requirement should be expanded to include the complete NSPS performance test requirement. Testing must be completed within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup.	Operating Permit changed as requested.
Page 90, X26	CHS believes that generating a log is unnecessary paperwork, especially since a facility modification and air quality permit would be required to burn fuel oil in the coker SRU incinerator. CHS believes that certifying no fuel oil was burned in this incinerator is adequate recordkeeping.	See response to Page 45, K42.
Page 92, 20 CFR 60 List	As discussed as part of EU014, 40 CFR 60 Subpart UU has been determined to be applicable to the refinery. The list should be updated here.	Operating Permit changed as requested.
Sec V, 19. C. NSPS Standards	Note that amendments to both NSPS Subpart J (Standards of Performance for Petroleum Refineries) and NSPS Subpart VV (Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry) have been proposed. NSPS Subpart GGG references the requirements of NSPS VV.	The Technical Review Document, Section V. page 19 has been updated to reflect the proposal of NSPS Subparts J, Ja, and VV.

Summary of Public Comments

Person/Group Commenting	Comment	Department Response
Bernie Gieser, ExxonMobil – Billings Refinery	ExxonMobil disagrees that Conditions A.26 and A.29 belong in the CHS Title V permit. These conditions are not applicable requirements as defined in Montana's Title V program, are not required by the CHS Consent Decree, and are in conflict with ARM 17.8.1211(2).	The intent of the Title V operating permit program is to record all of the air quality requirements that apply to a source in one document. The terms and conditions listed in Section III.A.26 and III.A.29 should remain in the permit, because the Consent Decree is an applicable requirement as defined by ARM 17.8.1201(10) and it contains relevant terms and conditions as required under ARM 17.8.1211(1)(c).
Randall Richert, ConocoPhillips – Billings Refinery	ConocoPhillips Billings Refinery has similar concerns (as the CHS and ExxonMobil comments), given that we are a party to a similar Consent Decree. We do not believe that all of the provisions in the Consent Decree are meant to be incorporated in Title V permits. Rather, our Consent Decree specifies that "emission limitations" must be incorporated into a federally-enforceable permit. We believe that the intention during the Consent Decree development was to only require emission limitation and the applicability of specific Clean Air Act standards as part of the permitting obligations under the Consent Decrees. This is supported by the specific language contained in the Consent Decrees regarding the permitting obligations. Further, as described in more detail in the ExxonMobil and CHS comments, the inclusion of Consent Decree obligations that are neither emission limitations nor emission standards is not supported by Montana air rules.	The intent of the Title V operating permit program is to record all of the air quality requirements that apply to a source in one document. The terms and conditions listed in Section III.A.26 and III.A.29 should remain in the permit, because the Consent Decree is an applicable requirement as defined by ARM 17.8.1201(10) and it contains relevant terms and conditions as required under ARM 17.8.1211(1)(c).

Summary of EPA Comments

Permit Reference	EPA Comment	Department Response
	None received.	

SECTION IV. REQUIREMENTS NOT IDENTIFIED AS NON-APPLICABLE

Pursuant to ARM 17.8.1221, CHS requested a permit shield for all non-applicable regulatory requirements and regulatory orders identified in the tables in Section 8 of the permit application. In addition, the CHS permit application also requested a permit shield for both the facility and for certain emission units. The Department has determined that the requirements identified in the permit application for the individual emission units are non-applicable. These requirements are contained in the permit in Section IV - Non-applicable Requirements.

The following table outlines those requirements that CHS had identified as non-applicable in the permit renewal application, but will not be included in the operating permit as non-applicable. The table includes both the applicable requirement and reason that the Department did not identify this requirement as non-applicable.

Applicable Requirement	Reason for Not Including
40 CFR 63, Subpart ZZZZ	This rule has become applicable since the submittal of the renewal application.
Consent Decree CV-03-153-BLG-RFC (entered 2/23/04)	The Consent Decree is required to be included in the Title V Operating Permit under ARM 17.8.1211.

SECTION V. FUTURE PERMIT CONSIDERATIONS

A. MACT Standards

The Department is not aware of any proposed or pending MACT standards, in addition to those already listed, that may be applicable.

B. NESHAP Standards

The Department is not aware of any proposed or pending NESHAP standards, in addition to those already listed, that may be applicable.

C. NSPS Standards

The Department is not aware of any proposed or pending NSPS standards, in addition to those already listed, that may be applicable at this time. However, CHS will be subject to applicable requirements in the proposed modifications to 40 CFR 60, Subpart J, once finalized. In addition, CHS will be subject to any applicable changes to 40 CFR 60, Subpart VV (proposed November 7, 2006).

D. Risk Management Plan

This facility does exceed minimum threshold quantities for any regulated substance listed in 40 CFR 68.115 for any facility process. Consequently, this facility is required to submit a Risk Management Plan.

If a facility has more than a threshold quantity of a regulated substance in a process, the facility must comply with 40 CFR 68 requirements no later than June 21, 1999; 3 years after the date on which a regulated substance is first listed under 40 CFR 68.130; or the date on which a regulated substance is first present in more than a threshold quantity in a process, whichever is later.

E. Compliance Assurance Monitoring (CAM) Plan

An emitting unit located at a Title V facility that meets the following criteria listed in ARM 17.8.1503 is subject to Subchapter 15 and must develop a CAM Plan for that unit:

- The emitting unit is subject to an emission limitation or standard for the applicable regulated air pollutant (other than emission limits or standards proposed after November 15, 1990, since these regulations contain specific monitoring requirements);
- The emitting unit uses a control device to achieve compliance with such limit; and
- The emitting unit has potential pre-control device emission of the applicable regulated air pollutant that are greater than major source thresholds/

CHS does not currently have any emitting units that meet all the applicability criteria in ARM 17.8.1503, and is therefore not currently required to develop a CAM Plan.